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The study is based on three FGD-units which are installed at three oil-fired, industrial boilers respectively with a maximum continuous heat input of 130 MW (27 MW + 2x51.5 MW) corresponding to approximately 50 MWE (10 MWE + 2x20 MWE) generating capacity for a power plant having a net efficiency of 38%.

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COMMITTEE ON THE CHALLENGES OF MODERN SOCIETY

Flue Gas Desulfurization Pilot Study Phase I — Survey of Major Installations - Sea Water Scrubbing Flue Gas Desulfurization Process

Appendix 95-D

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NORTH ATLANTIC TREATY ORGANIZATION

NATO-CCMS STUDY

PHASE I

Flue Gas Desulfurization Pilot Study Phase I

Survey of Major Installations - Sea Water Scrubbing Flue Gas Desulfurization Process

APPENDIX 95-D

Lead Country - Norway

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SUMMARY

An assessment study of the sea water scrubbing process for flue gas desulfurization has been made by SINTEF. This project has been financially supported by The Royal Ministry of Environment in Norway.

The study is based on three FGD-units which are installed at three oilfired, industrial boilers respectively with a maximum continuous heat input of 130 MW (27 MW + 2 x 51.5MW) corresponding to approximately 50 MWe (10 MWe + 2 x 20 MWe) generating capacity for a power plant having a net efficiency of 38%.

Measurements of sulfur oxides, nitrogen oxides, heavy metals and polynuclear aromatic hydrocarbons (PAH) have been carried out by SINTEF at one unit of 20 MWe size. The measurements are assumed to be representative for all units, since the units are very nearly identical.

Operational experience and cost data has been gathered since start up in September 1975 for the 10 MWe unit and since February 1977 for the 20 MWe units.

The scrubber efficiency on sulfur dioxide has been measured to be better than 99% at maximum load.

The process is simple in operation and significant operational problems have not been registered. No tendency of clogging in the scrubber, the sea water system or in the demister, has been observed. The average availability factors for a six months period of these FGD-units at the 10 MWe boiler and the two 20MWe boilers have been 96.4, 98.5 and 99.0%, respectively.

The flue gas temperature after the scrubber was low and close to the sea water temperature, and the flue gas, therefore contains negligible amounts of water vapour. The fog formation in the scrubbing tower appears to be small. No downwash of the plume has been observed by SINTEF. Provisions for reheating of the flue gas 25°C by means of hot flue gas by-passing the economizer, exist. These are only used during unfavorable weather conditions. During reheat the scrubber efficiency on sulfur dioxide may be decreased to 93-94%.

This throw away process implies that the components removed from the flue gas are discharged to the sea. Approximate computations of the dispersion in different sea recipients therefore have been made to assist an environmental assessment study. The dispersion estimates are computed for scrubber installations at a 20 MWe boiler and at a 1200 MWe power plant. For both alternatives the estimates indicate an acceptable dilution of the pollutants in the near-field-zone.

The sea water scrubbing process is applicable to flue gases from power plants using sea water for cooling and to flue gases from industrial boilers located near the sea. The excess sea water temperature will be relatively insignificant increased by the sea water scrubbing process itself.

The capital cost factor (1976) for the total 50 MWe FGD-installation at Porsgrunn is 43.2 $/kWe. The operating cost factor based on 8000 operating hours per year at maximum load and no reheat is calculated to 0.14 ¢/kWeh.

1. BACKGROUND AND INFORMATION

This report is one of a series on the status of Flue Gas Desulfurization Process in the NATO Countries and Japan. In this program, the United States, the Federal Republic of Germany, and Norway each acted as lead countries to gather information and prepare reports on FGD processes.

This report will deal with the Fläkt-Hydro flue gas desulfurization process, which has been developed jointly by Norsk Hydro a.s. and A/S Norsk Viftefabrikk, the Norwegian subsidiary of AB Svenska Fläkt-fabriken (Fläkt).

* * * * *

The principle of the Fläkt-Hydro FGD-process of employing sea water as a scrubbing agent is not new. The Electrolytic Zinc Company in Tasmania has used tidal water as the absorbent for the removal of sulfur dioxide from smelter gas since around 1949. /1/. Scrubbers for removing fluorides at the A/S Årdal and Sunndal Aluminium plant in Norway also removes 80-90% of the sulfur dioxide content utilizing sea water. The scrubbers are installed in the pot-exhaust system. /2/.

Laboratory investigations on the absorption of sulfur dioxide in sea water have been made by L. A. Bromley. /3/, /4/.

Research and development of the Fläkt-Hydro process were started in 1971 with laboratory investigations. The basic development of the process was completed during the summer 1973 after having carried out tests on a pilot plant with a gas capacity of approximately 10 000 Nm^3/h.*

The first commercial Fläkt-Hydro unit was installed in August 1975 on an existing 10 MWe boiler. At present there are two new commercial units in operation each serving 20 MWe boilers. A fourth unit of the same size is now under commissioning. All the commercial units mentioned are located at Norsk Hydro, Porsgrunn Fabrikker.

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* Nm^3 = unit volume of gas referred to standard conditions (0^oC and 1.01325 bar).

2. GENERAL PROCESS DESCRIPTION

2.1 Chemistry

The Fläkt-Hydro process is based on the utilization of the alkalinity of sea water to absorb and neutralize SO_2. Sea water contains bases corresponding to weak acids, such as bicarbonate, carbonate, borate, phosphate, arsenite and sulfide and has a considerably higher buffer capacity than fresh water. This is illustrated in figure 1 which shows the effect on pH by the addition of sulfuric acid to sea water and fresh water, respectively.

The fundamentals in the process are shown by the following chemical equilibria and reactions /2/, /5/:

$$SO_2\,(g) \rightleftharpoons SO_2\,(aq) \qquad (1)$$

$$SO_2\,(aq) + 2\,H_2O \rightleftharpoons HSO_3^- + H_3O^+ \qquad (2)$$

$$HSO_3^- + H_2O \rightleftharpoons SO_3^{2-} + H_3O^+ \qquad (3)$$

$$CO_2 + H_2O \rightleftharpoons H_2CO_3 \qquad (4)$$

$$H_2CO_3 + H_2O \rightleftharpoons HCO_3^- + H_3O^+ \qquad (5)$$

$$HCO_3^- + H_2O \rightleftharpoons CO_3^{2-} + H_3O^+ \qquad (6)$$

$$H_xA + H_2O \rightleftharpoons H_{x-1}A^- + H_3O^+ \qquad (7)$$

A = { arsenate, borate, phosphate, sulphide }

$$SO_3^{2-} + \tfrac{1}{2}\,O_2 \longrightarrow SO_4^{2-} \qquad (8)$$

The buffer capacity, results mainly from the equilibrium between carbonic acid and its corresponding bases ($CO_2/H_2CO_3/HCO_3^-/CO_3^{2-}$). The total alkalinity for uncontaminated oceanic sea water is normally 2.3-2.5 meq/l, and the pH is about 8.3.

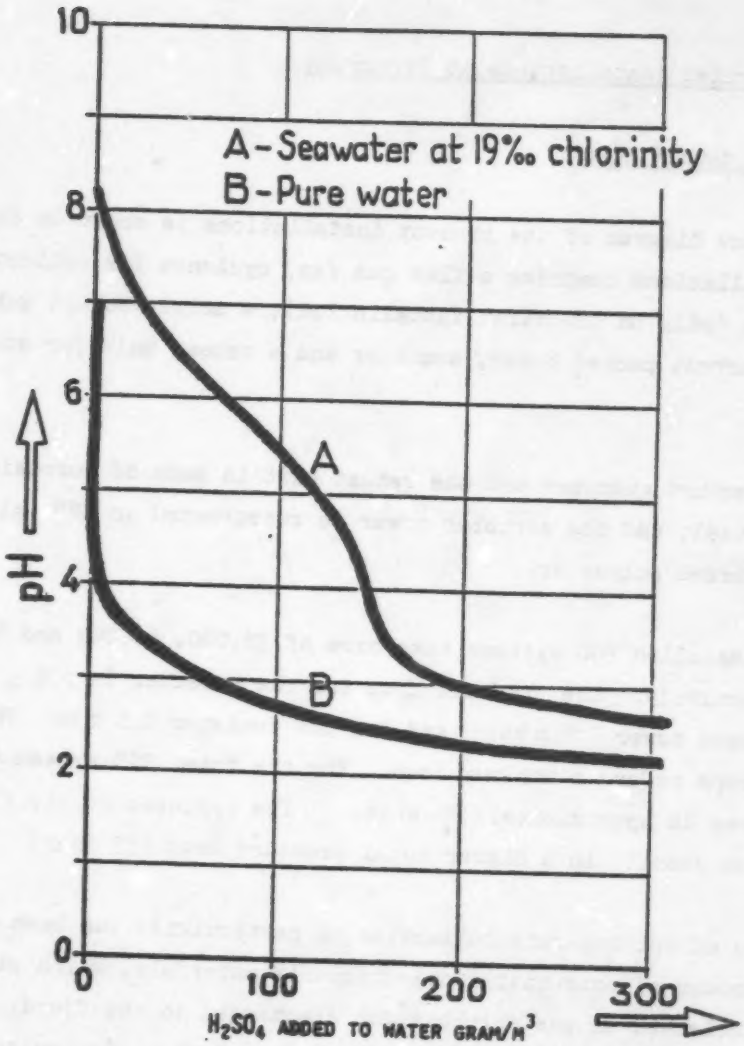

Fig. 1. The buffer capacity of pure water and sea water. /5/.

In this process, sulfur dioxide is absorbed in sea water and converted mainly to bisulfite (HSO_3^-) according to the equilibria (1-3). The oxidation reaction 8 will finally convert the bisulfite into sulfate.

2.2. Commercial installations at Porsgrunn

2.2.1. Plant description

A general flow diagram of the present installations is shown in figure 2. The installations comprise a flue gas fan, cyclones for collection of particulates (only on the first installation), a multi venturi quencher, a counter current packed tower, demister and a reheat unit for stack gas.

The multi venturi quencher and the reheat unit is made of corrosion resistant steel, and the scrubber tower is constructed in GRP (glas-fiber-reinforced polyester).

The three installed FGD systems take care of 35,000, 60,000 and 60,000 Nm^3/h*, respectively. The pressure drop for the quencher is 2.5 m bar, for the packed tower 7.5 m bar and for the demister 0.5 m bar. These pressure drops refer to maximum load. For the total FGD system the pressure drop is approximately 24 mbar. The cyclones in the first installation result in a higher total pressure drop (35 mbar).

The purpose of the separate collection of particulates has been to reduce the amount of potentially objectionable materials, which otherwise might be collected in the scrubber and discharged to the fjord. The cyclones was installed before one had experienced that particulates containing heavy metals were of an extremely small size. (See chapter 2.2.2).

The reheat unit is a simple unit for mixing in a small, adjustable by-pass stream of hot flue gas taken from the inlet to the economizer. This is done to achieve sufficient plume rise and dispersion of the

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* Nm^3 = Unit volume of gas referred to standard conditions (0°C and 1.01325 bar).

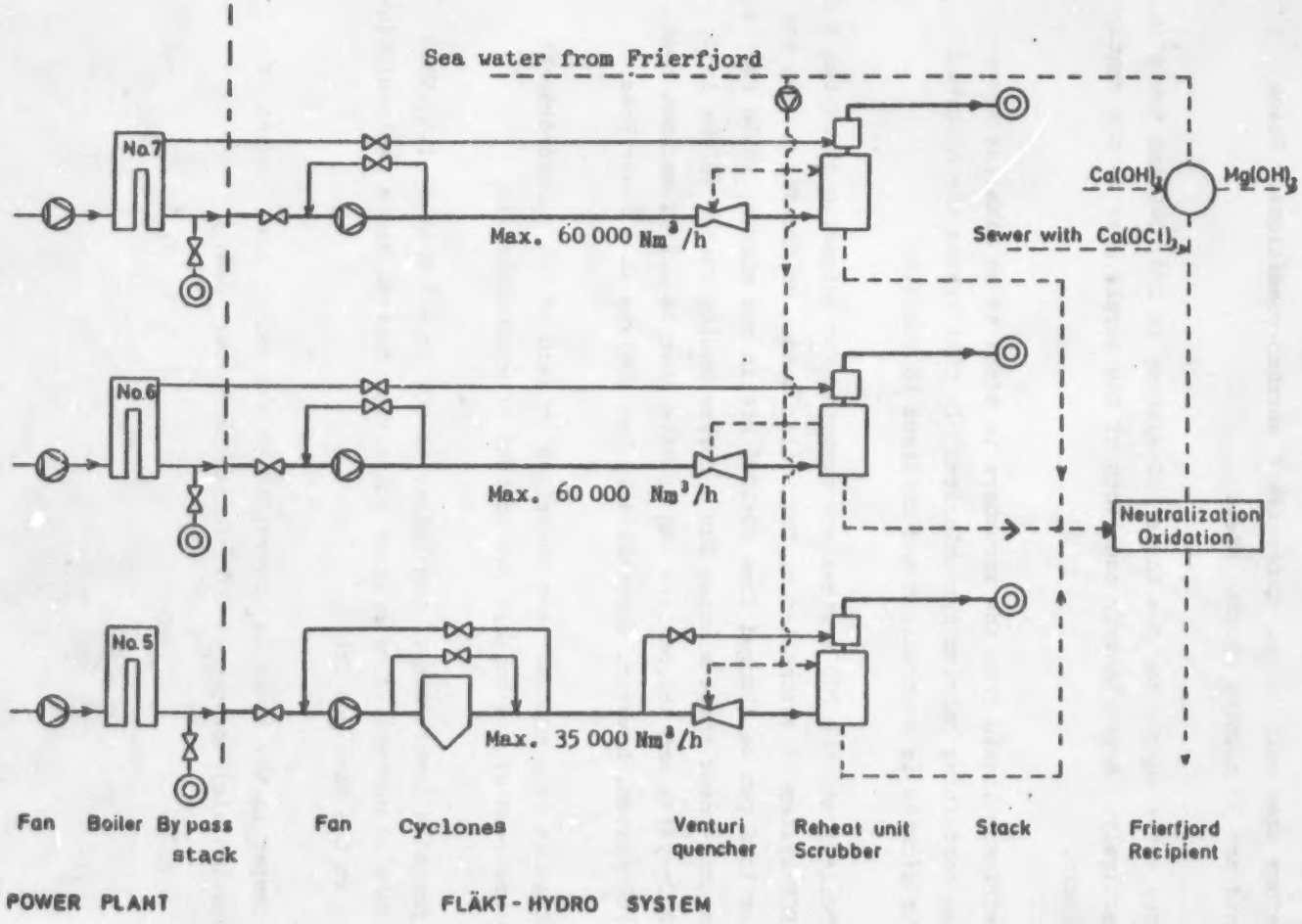

Fig. 2. Fläkt-Hydro FGD-system
Steam boiler station, Porsgrunn fabrikker.

emissions. The reheater is designed to give a maximum temperature increase in the flue gas of 25°C. Experience has shown, however, that the plume rise and dispersion is better than expected. The reheater is therefore used only during unfavorable weather conditions. Stack heights are 38 m above ground level.

The sea water supply for the three FGD-systems is 270, 540 and 540 m^3/h, respectively. Approximately one tenth of the supply goes to the venturi-quenchers.

The effluent liquid from the scrubbers is added to an alkaline sewer system containing calcium hypochlorite. In this system the absorbed sulfur dioxide is neutralized and oxidized to sulfate.

The boilers and the FGD systems are equipped for automatic operation and the FGD system is controlled by the boiler load. On the first unit the boiler load can be changed from 20-100% within one minute, while the two other units need three minutes for a corresponding change in the load. The FGD-system and the boilers can operate down to 20% of maximum load. The FGD-system, however, theoretically can operate at a lower load.

Inlet guide vane controls are installed on each of the forced-draught fans upstream of the boilers for control of combustion air.

The pressure downstream of the boiler is set to ÷ 1 mbar ($\pm$ 1.5).This pressure is controlled by an inlet guide vane control and a recirculation shunt at the flue gas fan.

The damper in the shunt is controlled by the boiler load (amount of combustion air) between 20-60% of maximum boiler load.

2.2.2. Measurements by SINTEF (Summary)

SINTEF and the respective companies have carried out measurements of several components both in the flue gas at the inlet and the outlet of the scrubber and in the scrubber liquid. A summary of the results obtained by SINTEF for the scrubber on boiler no. 7 (20 MWe) is given in tables 1 - 4. /6/. Similar results have been obtained by the companies through measurements on boiler nos. 5 and 6.

The procedure of the measurements compares closely to the EPA standards. The main difference is the temperature of the filter holder of the sampling train where SINTEF used 90°C instead of 121°C. Corrections for sulfuric acid mist on the filter are made.

Measurements were performed at two different operating conditions for the boiler, namely 100% and 50% of the maximum boiler load. Mainly, the results from 100% boiler load are given in this summary. For extensive informations and results from the 50% boiler load conditions, reference is made to the separate report on measurements. /6/. Complete results of the particle size distribution and distribution of heavy metals in the different fractions are also given in the cited.

The concentration of heavy metals and polynuclear aromatic hydrocarbons (PAH) in the scrubber liquid differ significantly between measurements. The removal efficiencies are therefore based on measurements in the flue gas. For the sulfur mass balance the different results matches fairly well with a maximum deviation of 4% from the sulfur content in the oil.

As to the particles size distribution (investigated with an in-stack cascade impactor) we may conclude that 60-80% by weight of the particles belong to the fraction with particle size less than 5 µm. Furthermore, approximately 70% of the nickel and 60-70% of the vanadium is found in the particles with smaller size than around 1 µm. Even particles with smaller size than 0.25-0.4 still contains around 50-60% of the heavy metals.

Table 1. Data for the oil used in boiler no. 7 at Norsk Hydro a.s. Porsgrunn Fabrikker

OPERATING DATA	
Oil consumption at max. load	4 500 - 4 700 kg/h
ANALYSIS OF COMPONENTS IN OIL	
Sulfur	2.1 - 2.5% S (by weight)
Ash*	0.06 - 0.1%
Vanadium*	132 - 160 mg V/kg oil
Nickel*	39 - 63 mg Ni/kg oil
Water*	2.0 - 2.45%

* 4 - 5% soot from ammonia production is mixed into the heavy oil used.

Table 2. Summary of results from measurements in the flue gas on the unit at boiler no. 7 at Norsk Hydro a.s., Porsgrunn Fabrikker. Boilers operated at 100% load and no reheating.

	Unit [1]	Scrubber Inlet	Scrubber Outlet
Flue gas stream	Nm^3/h	57 000	50 000
Flue gas temperature	^oC	210	5 - 7
Sulfur dioxide concentration[2]	mgS/Nm^3	1960 - 2080	12.7 - 14.4
Particulate concentration	mg/Nm^3	~100	70 - 80
Nickel in particulate, concentration in flue gas	mg/Nm^3	2.4 - 2.9	1.6 - 2.1
Vanadium in particulate, concentration in flue gas	mg/Nm^3	6.3 - 7.4	2.9 - 3.5
Polynuclear aromatic hydrocarbons concentration (Sum of 3 fractions)	$\mu g/Nm^3$	7.3 - 38.3[3]	-
Nitrogen oxides concentration	ppm NO_x ppm NO_2	220 - 250 ≤ 10	210 - 230

[1] Nm^3 = unit volume of gas referred to standard conditions (0^oC and 1.01325 bar).

[2] Both sulfur trioxide/sulfuric acid and sulfates in particulates are measured /6/.

[3] The high value is obtained under an operating condition with too low air excess in the boiler (sooting). The results are shown in detail in a measuring report /6/.

Table 3. Summary of results from measurements in the scrubbing liquid for the unit at boiler no. 7 at Norsk Hydro a.s., Porsgrunn Fabrikker.

	Unit	Scrubber Inlet	Scrubber Outlet
Sea water flow	m^3/h	530 - 540	-
Sulfite concentration	mg S/l	-	213 - 218
Sulfate concentration	mg S/l	871 - 884	
pH	pH		2.23 - 2.32
Nickel concentration	µg/l	8 - 9	80 - 310
Vanadium concentration	µg/l	0 - 11	250 - 540
Polynuclear aromatic hydrocarbon concentration	µg/l	< 1.0[1]	≤ 4.6[1]

[1] Data are uncertain as concentrations are close or below detection limit for the measuring equipment used. Comparing the individual measurements on the gas and liquid side, the mass balance does not comply.

Table 4. Absorption- and collection efficiencies.
Summary of results from measurements on the unit at boiler no. 7 at Norsk Hydro a.s., Porsgrunn Fabrikker.

		3)	4)
Sulfur dioxide absorption efficiency 100% load %		99.4	
Sulfur dioxide removal %	with maximum reheating 25°C	93	
Particulate removal in scrubber %		30-60	
Nickel removal in scrubber %	100% boiler load 1)	31-41	32-34
	50% " 2)	40-53	33-45
Vanadium removal in scrubber %	100% boiler load 1)	52-66	40-42
	50% " 2)	47-55	47-54

1) At 100% boiler load it was found that approximately 43-52% of the nickel and 32-40% of the vanadium content in the oil was retained by the boiler between soot blowing.

2) At 50% boiler load 13-23% of the nickel and 20-35% of the vanadium content in the oil was retained by the boiler.

3) Based on measurements in the flue gas.

4) Based on measurements in effluent water.

3. CURRENT STATUS AND PLANS

3.1. Summary of status of the surveyed FGD systems

The Fläkt-Hydro process has been in commercial operation since 1975. The status of the surveyed FGD-installations is shown in table 5 and 6. Boiler no. 5 - an old boiler - was equipped with the FGD-system in 1975 and the system has been in operation from August 1975 to late fall 1976. Boiler no. 5 was then shut down for overhauls and exists today as a stand-by installation.

Two new boilers no. 6 and no. 7 have been installed and equipped with the FGD-system. These units have been in operation since February this year. A new unit is under commissioning for boilers and process gas at a magnesium plant. All these installations are in the same industrial area in Porsgrunn. Presently, installations at oil refineries and oil or coalfired power stations are seriously considered.

Table 5. Summary of status of surveyed FGD systems

Total number of systems in operation	2 + 1 (stand-by installation)
Total number of systems built	3
Total number of systems surveyed	3
Year first placed in commercial service	1975
Number of utility systems using process	2 + 1 (stand-by installation)
Total MWe of these facilities	50
Number of industrial combustion systems	3
Range of SO_2 removal efficiencies	93-99.4 [1]
Range of fly ash removal efficiency	30-60% [2]
Range of availability factors	96.4 (85.3-100) [3] Boiler no. 5 98.5 (96.2-99.7) [3] " 6 99.0 (95.8-99.7) [3] " 7

[1] Overall sulfur dioxide removal efficiency of this FGD-system is decreased from 99.4% to 93% when flue gas is by-passed the scrubber for 25°C reheat of the stack gas.

[2] The concentration of particulates after the scrubbers is 70-80 mg/Nm^3

[3] The variation range for the availability factors is based on values which are registred monthly, see appendix.

Table 6. Status of surveyed FGD installations - Fläkt-Hydro process

Name of plant	Norsk Hydro Boiler no. 5	Norsk Hydro Boiler no. 6	Norsk Hydro Boiler no. 7
Location	Porsgrunn, Norway	Porsgrunn, Norway	Porsgrunn, Norway
Size, MWe	10	20	20
Fuel type	Heavy oil no. 6	Heavy oil no. 6 [1]	Heavy oil no. 6 [1]
Characteristics - % S - heat value, KJ/kg oil	Max. 3.0 41 000	Max. 3.0 41 000	Max. 3.0 41 000
Flue gas treated - Nm^3/sec - % of total	9.72 95-100	16.67 95-100	16.67 95-100
Sea water supply to scrubbersystem m^3/h	270	540	540
Year FGD-system started	Aug. -75	Febr. -77	Febr. -77
SO_2 Removal Efficiency	> 96,0	> 99 % [2]	> 99 % [2]
Disposition of End Products	Discharge in an alkaline sewer with calciumhypochlorite		
Energy required - Electricity kW - Heat loss during reheat max kW	155 0	220 250 (25°C reheat) [3]	220 250 (25°C reheat) [3]
Average Availability %	96.4	98.5	99.0

[1] 4-5% soot from ammonia production is mixed into the oil.

[2] With 25 °C reheat the efficiency will drop to 93-94%.

[3] Corresponds to 200°C heat loss of 5.7% by-pass of economizer.

3.2. Operational experience

The installations on boilers nos. 6 and 7 have proved troublefree after the start-up period. The first installation on boiler no. 5, however, did cause some problems. The main problem was the regulation of the gas flow and control of the pressure in the duct system. This problem was caused by rapid and considerable changes in load since the boilers take care of the variations in steam demand for the Norsk Hydro plant. After a preliminary period it was found necessary to install a shunt or re-circulation loop over the flue gas fan. The quantity of recirculated gas is determined by a damper which in turn is controlled by the flow rate of combustion air.

As to corrosion problems, the absorption towers are constructed of GRP (glasfiber-reinforced polyester) and all tower internals are also made of plastic materials. The quencher, however, is constructed of corrosion resistant metal because of contact with hot gases (160 - 380°C). In the opening phase there were corrosion problems in the cooling zone in the quencher for the installation on boiler no. 5. The corrosion problem for this unit was solved by changing the design. This modification caused an availability factor of 97.0% during March 1976 for unit no. 5. There have been no corrosion problems for the two new units.

For all the units there have been mechanical problems with the inlet guide vane control on the flue gas fans which gave a small decrease in the availability factors during several months. During soot-blowing the FGD-system occasionally has cut out, due to interlock system, in order to protect the scrubber materials against too high temperatures. The reason for the temperature rise was the use of steam for soot-blowing in the boiler.

The by-pass valve for the reheater has had a tendency to stick in boiler system no. 5. There is a small leakage stream ensuring the ducts temperature above the dew point of the gas.

Furthermore, some negligible overhauls in the sea water supply and discharge system such as the sea water pump and collection tank for the three units proved necessary.

All taken into consideration, we conclude that there is at present no major problem in the operation of the Fläkt-Hydro process. Reference is made to the average availability factors of 98.5% and 99% for units nos. 6 and 7, respectively

3.3 Fog formation

The fog emission from the Fläkt-Hydro process appears to be small. During measurements by SINTEF in March and June 1977 the light plume became invisible at a distance of 15-30 meter from the stack. No reheat was used, and stack gas temperature was 7 °C. Total water content (vapour + mist) was average 10 g/Nm³ and maximum 12 g/Nm³. Saturated air at 7 °C contains 8 g/Nm³ water vapour.

3.4 The applicability of the process

The sea water scrubbing process is applicable to fossil fuel fired power plants using sea water as a coolant and to fossil fuel fired industrial boilers located at a reasonable distance from sea.

As far as excess sea water temperature is concerned there should generally be no restrictions for boilers of 20 MWe size. The applicability of all types of thermal power plants using sea water as a coolant, however, is restricted by the allowable excess temperature in the sea recipient.

A 1200 MWe thermal power plant using sea water as a coolant would require a recipient capacity equivalent to the outer part of the Oslofjord at Slagentangen or even better the Skagerak sea at Tromøya outside Arendal. The excess temperature caused by the sea water scrubbing process itself would be small compared to the effect of effluent cooling water from the condensers.

3.5 Plans for installation in power plants

The sea water scrubbing process installed at Norsk Hydro a.s. is of a special type with respect to the size, separate particulate collection and treatment and discharge of the used sea water.

The Fläkt-Hydro-FGD-process will generally consist of the following main elements for installation in a power plant: a fan, separate particulate collector, quencher, scrubber, gas reheater, dilution and aeration unit. See figure 3.

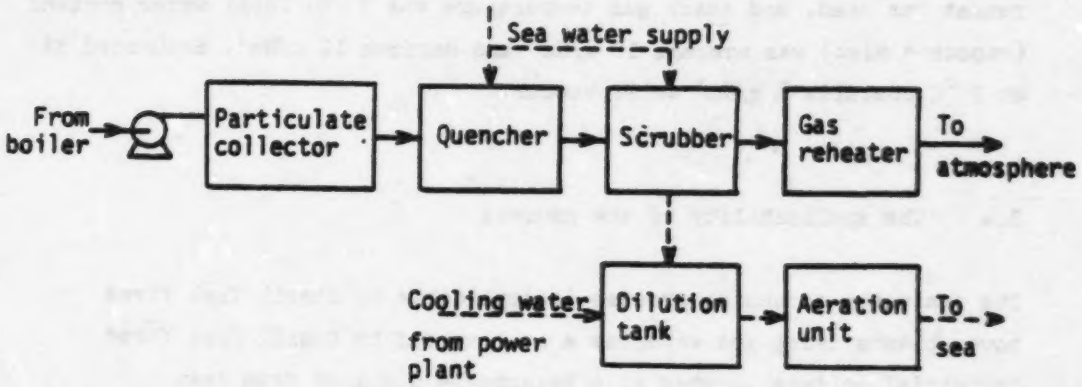

Fig. 3. Main elements in the Fläkt-Hydro-process in a power plant.

The problem of scaling up the process will mainly be related to the distribution of liquid and gas flow in the scrubbing tower.

The demand for particulate collection (precollector) will probably be the same as required with regard to atmospheric pollution in order to minimize effluent of objectionable materials which otherwise might be released.

In order to reduce the chemical oxygen demand (COD) in the used scrubbing liquid, it is necessary to have an oxidation unit. The sea water from the scrubber constitutes 14-20% of the cooling water stream from the condensers. The used scrubbing liquid will be mixed in the return cooling water to give a higher pH and lower concentrations. The dilute scrubber water will then be aerated in an oxidation unit before discharge.

The Water Resources and Electrical Board State Power System (NVE) is evaluating an oil or coal fired power plant installation in the Oslofjord region. Planned capacity is 600 MWe. A/S Norsk Viftefabrikk has projected and given a budget offer for the Fläkt-Hydro-FGD-system. The NVE has estimated total investment and operating costs based on this offer. It is assumed that the same electrostatic precipitator and the same stack height is required even if oil with low sulfur content is used. The figures given in Table 7 represent the estimated capital and operating costs for the FGD-system exclusive precollector and stack. /7/.

The cost for this FGD-system depends on the local conditions. Distance to-sea, sea water quality, regulations with regard to effluent, pH, COD and reheat requirements are factors of significance in the picture. /7/.

The main objections to the process deal with the discharge of sulfites, nitrogen oxides and heavy metals to the sea. Furthermore the degree of reheat requirements is being discussed. /8/. Several recent investigations conclude that the effluent water will cause only marginal local effects. /9/, /10/, /11/. (See next chapter).

Table 7. Capital and operating costs for the Fläkt-Hydro process in a planned 600 MWe power plant.
1976 costs based on 7000 hours max. load per year, 18% depreciation and interests.

Type of fuel		Coal	Oil
Capital cost	($/kWe)	30 - 50	24 - 40
Operating costs ¢/kWeh	Fixed charges: Capital	0.077 - 0.129	0.062 - 0.103
	Fixed charges: Other	0.006 - 0.009	0.005 - 0.008
	Variable costs	0.022 - 0.042	0.020 - 0.040
	Total	0.11 - 0.18	0.09 - 0.15

4. RECENT DEVELOPMENTS AND SOLUTIONS TO PROBLEM AREAS

4.1. Liquid disposal and dispersion

The sea water process depends fully on discharge of large amounts of used sea water and a thorough knowledge of the extent of the water pollution caused by this process is imperative. The effluent water from the scrubber contains sulfite and trace elements from the fuel as nickel and vanadium. The sea water temperature also increases when passing through the scrubber.

An assessment of the environmental impact is being made by the VHL (River and Harbour Laboratory affiliated with SINTEF). /11/. A summary of the most important basic conditions and the results obtained is given in this chapter.

4.1.1. Basic conditions

It is difficult to base a general environmental assessment of the sea water scrubbing process on the three scrubbers at Porsgrunn. This is because the scrubbers use a special alkaline sewer for the effluent water. Also extra soot is being mixed with the oil used in the boilers.

Instead of the existing scrubbers, two assumed installations, one of 20 MWe and one of 1200 MWe size, each working with heavy oil and sea water effluent, has been chosen in the further study. A typical size of an industrial boiler would be 20 MWe, while an oil based power plant of 1200 MWe is relevant as a supplement to existing hydro-electric power in Norway. The recipients chosen are a small fjord (Frierfjorden), a large fjord (Oslofjorden) and a sea area (Skagerak). The locations are shown in figure 4.

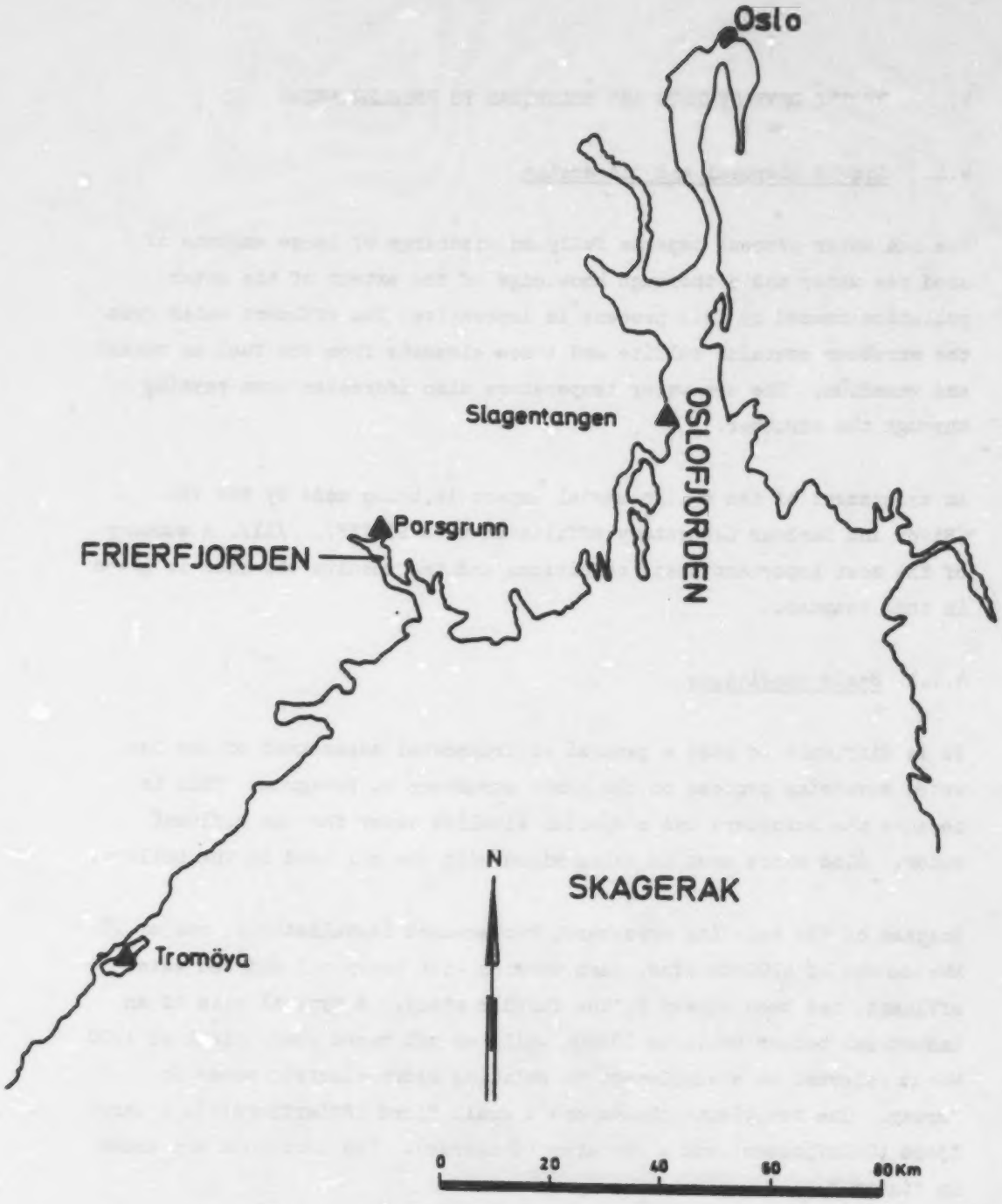

Fig. 4. Actual locations and recipients in the environmental assessment study done by VHL /11/

▲ Locations referred to in this chapter.

The basic conditions used in the calculations of concentrations of pollutants in the effluent water and in the recipient, are shown in Table 8.

For 20 MWe industrial boiler, data on nickel and vanadium retained in the boiler and the efficiency of the scrubber for the collection of these metals, are based on SINTEF data from the 20 MWe boiler no. 7 at maximum boiler load. /6/. The informations on frequency and duration of soot-blowing are taken from material published by AB Svenska Fläkt-fabriken. /2/. The calculated concentrations of nickel and vanadium during soot-blowing vary strongly with the frequency and duration of soot-blowing. Concentrations will decrease rapidly if the frequency and duration of soot-blowing are increased. The concentrations used in the calculations should be regarded as a worst case. 20 m below surface has been taken as a reasonable depth for intake and outlet of sea water. This arrangement usually prevents recirculation for small units. pH of the effluent water is estimated using data computed by Abdulsattar (1977). /12/. His data of pH versus sulfite concentrations added to sea water is based on a closed oxygen free sulfur dioxide - carbon dioxide - sea water system. The carbon dioxide produced by reaction of sulfur dioxide with water is assumed to remain in the liquid phase. Abdulsattar's model seems reasonably valid when the effluent water is <u>not</u> being diluted and aerated.

For the 1200MWe power plant it is assumed continuous soot-blowing. Furthermore, a precollector for the particulates will be required. For the 1200MWe power plant aeration of the effluent water will be required. The choice of oxidation efficiency should be based on an evaluation of the recipient capacity. An oxidation efficiency of 75% * is assumed as a reasonable value based on aeration time. A higher efficiency would require a considerable increase in the aeration time. The intake for sea water is placed 30 m below sea level and the outlet at the surface in order to minimize the re-circulation of liquid. It has been suggested that this type of arrangement will be most suitable for a 1200MWe power plant, at least for the Norwegian coastal waters.

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*defined as 75% oxidation of the sulfite

Table 8. Basic data in the dispersion study by VHL.
Impurity levels in oil used in the boiler and power plant: 2.5% S, 20 ppm Ni and 60 ppm V.
Sulfur dioxide removal efficiency of the scrubber is assumed to be 100%. No oxidation of sulfite is assumed, except during aeration. Operation at maximum load. No extra soot is mixed with the oil.

Size	20 MWe INDUSTRIAL BOILER	1200MWe POWER PLANT
Oil comsumption (t/h)	4.5	270
Total amount of effluent water (m^3/h)	540	180 000 (includes cooling water from the power plant)
Retained Ni and V in the boiler	50% of Ni and 40% of the V in the oil are retained by the boiler during the 24 hours, which is the time sequence of soot blowing. During the 10 minute soot blowing period, all the accumulated Ni and V is released to the scrubber.	Continuous soot blowing is used and all Ni and V in the oil is released continuously.
Collection efficiency of Ni and V in the scrubber	50% efficiency for the collection of Ni and V in the scrubber, is assumed during ordinary operation and soot blowing.	Only 27% of both Ni and V from the boiler is assumed collected by the scrubber, because an electrostatic precipitator is installed between the boiler and the scrubber.
COD of the effluent water	COD of the effluent water is equal to half of the sulfite concentration mgS/l.	COD of the effluent water is decreased by 75% with aeration of the mixture of scrubber and condenser cooling water.
Level of water intake	20 m below sea level	30 m below sea level
Level of water outlet	20 m below sea level	At sea level
Discharge velocities (m/s)	2 and 4	2
Number of outlets	1	1

pH of the effluent water after dilution and aeration is estimated from Bromley's (1972) experimental data obtained after simple spray into air of sea water containing sulfuric acid. /4/. His graph of pH of sea water as a function of alkalinity change caused by addition of sulfuric acid is shown in figure 5.

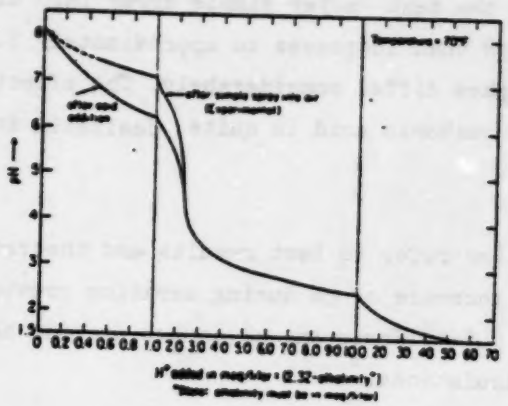

FIGURE 5. pH of sea water as a function of alkalinity change caused by addition of sulfuric acid. (i.e., Oxidized SO_2).

The chemical oxygen demand (COD) expresses the sulfite ion concentration due to the following reaction:

$$SO_3^{2-} + \tfrac{1}{2}\, O_2 = SO_4^{2-}$$

The chemical oxygen demand, COD (mgO_2/l), is, accordingly equal to half of the sulfite ion concentration expressed in mgS/l.

Table 9 shows the calculated concentrations of pollutants added to the total effluent water based on the conditions as given in Table 8.

Calculations of the chemical oxygen demand (COD) are based on the sulfite ion concentrations only. The oxygen content in sea water, which is used in the scrubbing process and for cooling water to the condensers, has not been taken into account. The COD value of the effluent water might therefore be too high and should be regarded as a worst case.

The estimated pH value is not completely verified. For the scrubber no. 5, pH varies with the load between 2.2 and 5.2. A pH value between 2.2

and 2.3 was registered at maximum load. For the 1200 MWe plant, a more detailed evaluation of the effect of oxidation is necessary. With no oxidation and no stripping of carbon dioxide, the pH according to Abdulsattar's model would be equal to 5.9. After oxidation a resulting effluent pH of 4.6 might be estimated on the basis of complete oxidation to sulfate using the lower graph with the text "after acid addition" in figure 5. Because carbon dioxide will be stripped off during aeration, the upper curve with the text "after simple spray into air", is more realistic, however. pH then increases to approximately 5. At higher pH, however, the two graphes differ considerabely. The effect of increasing pH due to removal of carbonic acid is quite desirable in moving the pH to a safe level.

The FGD-system supplier refer to test results and theoretical calculations indicating an increase of pH during aeration provided pH prior to aeration exceeds 5.5-6. Stripping of carbon dioxide have been considered in these calculations.

Table 9. Concentrations of pollutants added to the total effluent water based on the conditions in table 8.

Size of power plant (MWe)	20	1200
Total effluent water (m^3/h)	540	180 000 [1]
Conc. of nickel (µgNi/l)	42 (6000) [2]	8
Conc. of vanadium (µgV/l)	150 (14 400) [2]	24
Conc. of sulfur (mgS/l)	210	37
COD (mgO_2/l)	105	4.6
pH	2.6	approx.5 [3]
Temperature increase (°C)	10	10 [4]

[1] Effluent water from scrubber mixed with effluent cooling water from the power plant.

[2] Numbers in parenthesis are calculated for 10 minutes of soot blowing each 24 hours. Recent measurements indicate a considerably less retention of Ni and V in the boilers.

[3] Based on complete oxidation of sulfite. The calculated pH is possibly too lov because more CO_2 is stripped off during aeration, and because the oxidation of sulfite is not complete.

[4] For the 1200 MWe power plant the temperature rise of the effluent water is mainly caused by the cooling water from the condensers.

4.1.2. The recipients

An evaluation of the dilution in the so-called near-field-zone and the far-field-zone has been carried out at three different locations in southern Norway.

The near-field-zone is defined as the zone where the main dilution of the effluent water with the recipient is caused by the momentum of the discharge itself. The far-field zone is defined as the zone where the main dilution is caused by the general mixing process, which occurs in the recipient itself and is independent of the momentum of the discharge.

The locations of the effluents are Porsgrunn at Frierfjorden, Slagentangen at Oslofjorden and Tromöya outside Arendal at Skagerak as shown in figure 4.

Locations were chosen representing three different types and sizes of recipients. Sufficient data for rough estimates at these locations existed already.

In Table 10 are given some recipient characteristics for the three places.

The terms upper and lower layer being used in the table is defined as follows: The upper layer is located between the surface and the density jump. The lower layer is located between the sea bottom and the density jump. The density jump is located to the depth where a significant change in the vertical density gradient occurs. The density jump separates the upper brackish water masses from the lower and heavier saline water masses.

Table 10. Recipient characteristics for three different recipients in southern Norway

Effluent location	Porsgrunn	Slagentangen	Tromöya outside Arendal
Recipient	Frierfjorden	Oslofjorden	Skagerak
Location of the density jump (m below water surface)	1 - 7	5 - 15	0 - 30
Salinity of the upper layer °/oo	0.5 - 10	17 - 32	23 - 32
Water exchange in the upper layer (m^3/s)	90 - 580	1000 - 1800	Larger than 2000
Water exchange in the lower layer (m^3/s)	60 - 110	1000 - 1800	Larger than 2000

4.1.3. Results

The results for the 20 MWe industrial boiler are summarized in Table 11.

Table 11. Results related to the 20 MWe industrial boiler

Constituents	Excess concentration at the end of the near-field-zone	Average daily excess concentration in the far-field-zone		Concentration in a non-polluted recipient
		Frierfjorden	Slagentangen	
Ni, µg/l	1-2(200-300)*	0.1 - 0.2	< 0.1	- 2
V, µg/l	5-8(400-800)*	0.3 - 0.6	< 0.1	- 2
Excess temp. °C	0.5	< 0.1	< 0.1	-
COD, mgO_2/l**	3-5	0.1 - 0.2	< 0.1	0
pH	6.6 - 6.7	-	-	7.5 - 8.3

* The numbers in the parenthesis refer to concentrations calculated for the periods of soot-blowing of the boilers.

** COD defined as the equivalent sulfite content only, not considering the O_2-content (see page 22).

The results from the table indicate that the Ni- and V-concentrations obtained by the near-field dilution are of the same order of magnitude as the concentrations found in natural sea water. /9/, /10/. However, during the periods of soot-blowing, considerably higher concentrations are reached. These will, on the other hand, only persist for very short periods of time.

The lowest oxygen concentrations, which biologists claim is critical for marine life is 3 mgO_2/l. The actual oxygen concentration in the recipient is not directly shown by table 11. This value depends on the oxidation rate of the sulfite ion. No oxidation is

assumed in this calculation, however, to give a worst case example. The lowest possible net oxygen concentration might be estimated by subtracting the chemical oxygen demand from the concentration of oxygen in a non-polluted recipient.

The results for the 1200 MWe power plant are summarized in the following table:

Table 12. Results related to the 1200 MWe power plant. Electrostatic precipitator is assumed to be installed prior to the scrubber. Soot-blowing is assumed to be carried out continuously.

Constituents	Excess concentration after dilution in the near-field zone	Average excess concentration in the far-field zone		Concentration in a non-polluted recipient
		Slagentangen	Tromöya	
Ni, µg/l	1 - 2	0.2 - 0.4	< 0.2	- 2
V, µg/l	5	0.7 - 1.2	< 0.5	- 2
Excess temp. °C	0.8 - 2.9	0.5	< 0.5	-
COD mg O_2/l [3]	1 [1]	0.4 - 0.8	< 0.4	0
pH	6.8 [2]	-	-	7.5 - 8.3

[1] These numbers are based on the assumption that the discharge has been aerated before entering the recipient. Without aeration, the numbers would be considerably higher (with a factor of max. 4)

[2] The number is the same for both aeration and no aeration of the discharge, according to Bromley /4/.

[3] COD defined as the equivalent sulfite content only, not considering the O_2-content (see page 22).

When entering the far-field-zone, both the Ni- and V-concentrations from the discharge are reduced to the order of magnitude that is found in natural sea water. Continuous soot blowing is here assumed. (see 4.1.1). With other soot blowing procedures this situation might change.

The excess temperatures may be as high as 3°C when entering the farfield-zone. This value is considerably in excess of the 1°C temperature rise which biologists claim may be critical for marine ecosystems. This problem is, however, common for all types of thermal power plants using sea water as a coolant.

4.1.4. Oxygen content in effluent water

The aerated effluent water will contain free oxygen. Tests made by the supplier indicate an oxygen content of 5 mg O_2/l in compliance with 75% oxidation as used in the recipient evaluation. By dilution in the near- and far-field-zone, COD and O_2 will approach the background concentrations.

4.2. Reheating of stack gas

The water vapor content in the stack gas is particularly low, because the gas temperature at the scrubber outlet is close to the inlet sea water temperature. The need for reheating is therefore mainly concerned with the NO_x-emission. The Norwegian Institute for Air Research (NILU) has studied the effect of the stack heights and the degree of reheating to satisfy a maximum ground level concentration of 320 µg NO_2/m^3 /8/. The report concludes that two stacks of 150 m for a 2 x 600 MWe power plant will not require reheat if the EPA regulations on NO_x emission is met for the boiler operation.

4.3. Current research

The current research on the Fläkt-Hydro process is mainly concerned with the treatment of the effluent scrubber liquid. A/S Norsk Viftefabrikk has carried out laboratory investigations on the dilution and aeration of the used scrubber liquid. More detailed studies are planned to be carried out in a pilot plant.

5. COSTS [1.]

Table 13 shows the 1976 costs for FGD-plant no 5, 6 and 7 based on the data given. (See appendix point 5 in the questionnaire). An exchange rate of 0.18 $/N.kr. is used.

The total variable costs constitutes electricity costs for fans and booster pumps, costs of sea water from existing installation (pumping and distribution) and maintenance costs. The unit costs used are:

Electricity: 13.5 mills [2.] /kWe
Sea Water : 4.5 mills/m^3

Maintenance costs per year are estimated to 20,000 $. No extra operator is required at the boilers.

Reheat costs are not included in table 13. Provision is made for by-passing max. 6% of the flue gas (400 °C) taken in front of the economicer. The increased energy expenditure for steam production corresponds to a fall in temperature of 200 °C of the by-passed stream. A by-pass of 6% would give a temperature increase in the stack gas outlet of approximately 25 °C and an increased energy expenditure of approximately 650 kW.

For the calculation of costs per unit theoretical generated electric power it is assumed that the maximum continuous heat input of 130 MW would give a generating capacity of 50 MWe for a power plant, which gives a net efficiency of approximately 38%. This might be reasonable for a power plant producing electricity only. For industrial boilers, however, a net efficiency of 33% is more relevant.

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1. Cost estimates for a planned power plant are given in chapter 3.5 page 18.

2. 1 $ = 1000 mills.

The calculation of net variable costs for 8000 and 4000 operating hours per year at maximum continuous generating capacity is shown below:

The energy requirement for fans and booster pumps is 600 kWe. (See appendix point 6 in the questionnaire). Annual electricity costs at 8000 operating hours would be:

$$600 \times 13.5 \times 8000/1000 \text{ \$/year} = 64\,800 \text{ \$/year}$$

Sea water flow is 1350 m^3/h (See appendix point 4.6.2 in the questionnaire). Annual costs of sea water from existing installation at 8000 operating hours would be:

$$1350 \times 4.5 \times 8000/1000 \text{ \$/year} = 48\,600 \text{ \$/year}$$

Maintenance costs are estimated to 20 000[1] \$/year regardless of operating hours/year and continuous generating capacity. Total variable costs at maximum continuous generating capacity and 8000 operating hours per year would thus be 133400 \$/year corresponding to $\frac{133400}{8000 \times 50}$ mills/kWeh = <u>0.33 mills/kWeh.</u>

This net variable cost is given with one decimal in table 13 point 4. With 4000 operating hours per year the variable cost factor would be <u>0.38 mills/kWeh</u>. This number is also given with one decimal at the bottom of table 13.

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[1] The maintenance cost of 20 000 \$/year is referred to a new plant and might increase slightly with plant age.

TABLE 13. Cost summary for FGD units [1]

COMPANY NAME PLANT NAME LOCATION	NORSK HYDRO a.s. PORSGRUNN FABRIKKER HERØYA, NORWAY		
1. CAPITAL COSTS	Year		1976
	Total	($)	2.160 000
		($/kWe)	43.2
2. ANNUAL COSTS	Total variable cost	($)	125 000
	Fixed charge factor	(%)	20
	Total fixed costs	($)	430 000
3. BOILER OPERATION	Time	(hours/year)	8760
	Capacity factor		0.35
	Generated [2]	(MWeh)	153 300

4. NET ANNUAL COSTS (mills [3] /kWeh)

OPERATION HOURS	CAPACITY FACTOR	VARIABLE COSTS	FIXED COSTS	TOTAL COSTS
8760	0.35	0.8	2.8	3.6
8000	0.91	0.3	1.1	1.4
4000	0.46	0.4	2.2	2.6

[1] Based on 0.18 Nkr./$

[2] 130 MW max. continuous heat input. Theoretical electric generating capacity is assumed to be 50 MWe.

[3] 1 $ = 1000 mills.

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APPENDIX

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7
1.	GENERAL DESCRIPTION	
1.1	Company	Norsk Hydro a.s.
1.2	Plant name	Porsgrunn Fabrikker
1.3	Preparers name and mailing address	E. Thurmann-Nielsen, Norsk Hydro a.s., 3901 PORGSRUNN, Norway. Phone (035)51120 B. Hebnes, A/S Norsk Viftefabrikk, Ole Deviksvei 10, OSLO 6, Norway. Phone (02)190600
1.4	Principal plant products	Fertilizers, Magnesium, PVC
	Brief description of area surronding plant site and factors for choice of FGD system	Industrial area located close to the inner part of Frierfjorden. See map in appendix 1.
1.5	Plant location	Porsgrunn, Norway.
1.6	STATION CAPACITY	No electric power generation. Max. continous heat input = 130 MW corresponding to approximately 50 MWe for a power plant having a net efficiency of 38%.
1.6.1	Total boiler generating capacity (MWe) number of boilers	Corresponds to appr. 50/3
1.6.2	Capacity served by FGD system amount of flue gas treated (Nm^3/h)*	155 000
	% of boiler flue gas treated by FGD system	100
	Number of boilers served	3

* Nm^3 = unit volume of gas referred to standard conditions (0°C and 1.01325 bar).

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7	BOILER No 5	BOILER No 6	BOILER No 7
1.7	TYPE OF FGD SYSTEM	None regenerable sea water scrubbing			
1.8	Number of scrubber trains in parallel	3	1	1	1
1.9	FGD system installed on new or existing boiler		Exist	New	New
1.10	STATUS OF FGD SYSTEM operational or under construction, date started	Operational	Started Aug. -75	Started Febr. -77	Started Febr. -77
2.	BOILER DATA				
2.1	Boiler identification number		5	6	7
2.2	Maximum continous heat input * (MW)	130	27	51.5	51.5
2.3	Max. cont.net generating capacity	1.5×10^5 kg steam/h No electric power generation			
2.4	Flue gas flow rate (Nm^3/h) Temperature at induced draft fan (^oC)	155 000	35 000 380	60 000 200	60 000 200
2.5	Boiler manufacturer		Moss Rosenberg Verft A/S, Moss Verft	AB Svenska Maskinverken	AB Svenska Maskinverken

* Oil input

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7	BOILER No 5	BOILER No 6	BOILER No 7
2.5.1	Fuel type		Heavy fuel oil	Heavy fuel oil with 5% wt soot added	Heavy fuel oil with 5% wt soot added
2.5.2	Firing configuration		Rotating burner	Steam atomizing burners	Steam atomizing burners
2.6	Year placed in service		1967	1977	1977
2.7	Type service	Steam for process			
2.8	Stack height (m)		38	38	38
2.8.1	Flue gas exit velocity (m/s)	Velocity at 35°C (6% by-pass to reheat unit)	13	9	9
2.9	Average boiler operation (h/a)		Stand by	8000 estimated for 1977	8000 estimated for 1977
2.10	Average boiler capacity factor *	0.35			
2.11	COAL COMPOSITION				
2.11.1	Lower heating value (kJ/kg) (kcal/kg)				
2.11.2	Sulfur content (%wt)				
2.11.3	Ash content (%wt)				
2.11.4	Chloride content (%wt)				
2.11.5	Moisture (%wt)				
2.12	OIL COMPOSITION	Heavy oil 6			
2.12.1	Grade/heating vaule (kJ/kg) (kcal/kg)	41000 approx. 9750			
2.12.2	Sulfur content (%wt)		Max 1.2	Max 3.0	Max 3.0
2.12.3	Ash content (%wt)		Approximately 0.02	Max 0.1	Max 0.1
2.12.4	Chloride content (%wt)				

* Capacity factor = $\frac{\text{Steam generated in typical year}}{\text{Maximum continous generating capacity} \times 8760 \text{ hours/year}}$

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

	TOTAL FOR BOILER No 5, 6 AND 7	BOILER No 5	BOILER No 6	BOILER No 7
2.13 PARTICULATE REMOVAL EQUIPMENT NOT PART OF FGD SYSTEM				
2.13.1 Type		Cyclones		
2.13.2 Manufacturer		AB Svenska Fläktfabriken		
2.13.3 Efficiency, % removal				
2.13.4 Emission rate (mg/Nm³)		50		

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7
3.	EMISSION REGULATIONS	
3.1	ATMOSPHERIC EMISSIONS	
3.1.1	SO_2	6 g/kg oil
3.1.2	Particulate	1.5 g/kg oil
3.1.3	NO_x	
3.1.4	Other	
3.1.5	Legal basis	National
3.2	RESTRICTIONS APPLICABLE TO LIQUID OR SOLID WASTES AND LEGAL BASOS OF REGULATION	No restrictions for the time being. Limits will be set later by National Authorities based on material from control program now on stream.
4.	FGD SYSTEM INFORMATION	
4.1	Process name	Fläkt-Hydro Process
4.1.1	Supplier or design company	A/S Norsk Viftefabrikk
4.1.2	WHY WAS THIS SYSTEM CHOSEN?	The system seemed to be promissing with regard to high efficiency, reliability, investment and operational cost. It seemed to be the best ecological solution to sulfur depositing problem.
4.1.3	Process description	See appendix 3 and figure 2 in main report.

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7
4.2	SO_2 SCRUBBING AGENT	
4.2.1	Name	Sea water
4.2.2	Chemical composition Components/% by weight	See appendix 4
4.2.3	Stoichiometric requirement	0.35 moles of reactive agent (HCO_3^- + CO_3^{2-} + $B(OH)_4^-$) per mole of sulfur in fuel*
4.2.4	Addition rate (kg/h)	1.386 x 10^6
4.2.5	Particle size (mm)	
4.3	REGENERATION AGENT	
4.3.1	Name	
4.3.2	Composition	
4.3.3	Stoichiometric requirement	
4.3.4	Addition rate	
4.3.5	Particle size	
4.4	SALEABLE PRODUCT	
4.4.1	Name	
4.4.2	Chemical composition Components/% by weight	
4.4.3	Amount generated/year (t/a)	
4.4.4	Sales potential	

* Based on 2.64% wt S in oil and concentrations of reactive agents in sea water equal to 2 mmol HCO_3^-/l, 0.2 mmol CO_3^{2-} and 0.35 mmol $B(OH)_4^-$/l.

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7
4.4.5	BY-PRODUCT RECOVER PROCESS	
	Name	
	Vendor	
	Process description	
4.4a	Intermediate product composition	
4.5	BY-PRODUCT NUMBER 2	
4.6	WASTE STREAMS	
4.6.1	Type of waste	Liquid
	% water	Approximately 100% sea water
4.6.2	Amount generated in one hour at full load (m^3/h)	1350
4.6.3	Disposal method	Surface discharge in the Frierfjord
4.6.4	Disposal site and distance from plant (km)	Approximately 0.5
4.6.5	Potential effects on environment from sludge disposal	No sludge. Potential effect of polluting components see: (1) E. Føyn, "Problems of fossil fuel combustion and waste". Environmental Pollution Management. March/April (1977). (2) G. Nilsen, "An assessment study of the discharge of effluent water from a sea water scrubbing process applied to oil fired power plants". (Norwegian text). Report O-135/75, NIVA Jan. (1976).
4.7	SLUDGE FIXATION PROCESS	

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7	BOILER No 5	BOILER No 6	BOILER No 7
4.8	FGD EQUIPMENT DATA				
4.8.1	FIRST SCRUBBER	Prescrubber (quencher)			
4.8.1.1	Type	Venturi			
4.8.1.2	Liquid (solid)/gas ratio (l/Nm^3)	0.65			
4.8.1.3	Gas velocity through absorber or scrubber (m/s)	12			
4.8.1.4	Absorbent (adsorbent) flow (m^3/h)	100			
4.8.1.5	Gas flow entering scrubber (Nm^3/h)	155 000			
4.8.1.6	Gas temperature (in→out) (^oC)		380 → 50	200 → 50	200 → 50
4.8.1.7	Gas composition *	**			
	SO_2 in→out (ppm)	1250 →			
	% removal				
	Particulate in out (mg/Nm^3)	100 →			
	% removal				
	NO_x in→out (ppm)				
	CO_2 in→out (ppm)	120 000 →			
	Other in→out				
4.8.1.8	Material of construction	Corrosion resistant metal			
4.8.1.9	Type of lining	None			
4.8.1.10	Adsorbent and sand losses				
4.8.1.11	Number of stages	1			
4.8.1.12	Packing type and composition	None			

* See 4.8.2.7

** Based on 2.5% S in oil.

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Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7
4.8.2	SECOND SCRUBBER	
4.8.2.1	Type	Tower
4.8.2.2	Liquid (solid)/gas ratio (l/Nm^3)	8
4.8.2.3	Gas velocity through absorber or scrubber (m/s)	1.9
4.8.2.4	Absorbent (adsorbent) flow (m^3/h)	1250
4.8.2.5	Gas flow entering scrubber (Nm^3/h)	155 000
4.8.2.6	Gas temperature in → out (^oC)	50 → 10 through scrubber
4.8.2.7	Gas composition	
	SO_2 in → out (ppm)	Min 97 without reheat. Min 90 with max reheat
	% removal	
	Particulate in → out (mg/Nm^3)	100-130 → 70-80 } Total for first and second scrubber.
	% removal	30- 40 }
	NO_x in → out (ppm)	
	% removal	
	CO_2 (ppm)	Approximately 120 000
	Other	
4.8.2.8	Material of construction	Glas fiber reinforced polyester (GRP)
4.8.2.9	Type of lining	None
4.8.2.10	Number of stages	1
4.8.2.11	Packing type and composition	Saddles

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7
4.8.3	CLEAR WATER TRAY	
4.8.3.1	Type	
4.8.3.2	L/G ratio	
4.8.3.3	Source of water	
4.8.4	DEMISTER	
4.8.4.1	Type	Chevron
4.8.4.2	Number of passes (stages)	1
4.8.4.3	Material of construction	PVC
4.8.4.4	Method of cleaning	No cleaning needed
4.8.4.5	Flow rate during cleanings (m^3/h)	
4.8.4.6	Frequency and duration of routine cleaning	
4.8.5	REHEATER	
4.8.5.1	Type	Hot flue gas by-pass (Max 9000 Nm^3/h at appr. 400 ^oC).
4.8.5.2	Heat load (kW)	Max. 650 (Corresponds to 200 ^oC heat loss of max. by-pass of economizer).
4.8.5.3	Heat transfer surface area (m^2)	
4.8.5.4	Temperature of gas in (^oC)	5 - 15
	out (^oC)	5 - 40
4.8.5.5	Reheater materials of construction	Corrosion resistant metal

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7	BOILER No 5	BOILER No 6	BOILER No 7
4.8.6	SCRUBBER TRAIN PRESSURE DROP DATA				
4.8.6.1	First scrubber (mbar)	2.5			
4.8.6.2	Second scrubber (mbar)	7.5			
4.8.6.3	Clear water tray (mbar)				
4.8.6.4	Demister (mbar)	0.5			
4.8.6.5	Reheater (mbar)	Approximately 0			
4.8.6.6	Ductwork (mbar)	13.5			
4.8.6.7	Total FGD system (mbar)		35 (incl. cyclones	24 (no cyclones)	24 (no cyclones)
4.8.6.8	I.D. fan Δp (mbar)		35	24	24
4.9	SYSTEM MAKE-UP WATER ADDED (m^3/h)				
4.9.1	Water added per mole of SO removed (m^3/kg mol)				
4.9.2	Source of make-up water				
4.9.3	Where is water added				
4.10	BYPASS SYSTEM				
4.10.1	Can flue gas be by-passed?	Yes			
4.10.2	Height of gas discharge when bypassed (m)			38	38
4.11	SLURRY DATA				
	pH/% solids by weight				
4.11.1	Fresh sorbent to scrubber				
4.11.2	Recirculating slurry				
4.11.3	Waste sorbent				

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Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7
4.12	SPENT SLURRY SYSTEM	
4.12.1	Clarifiers	None
4.12.1.1	Number	
4.12.1.2	Diameter (m)	
4.12.2	Solid separation	None
4.12.2.1	Type	
4.12.2.2	Cloth area (m^2)	
4.12.2.3	Capacity (wet cake) (t/h)	
4.13	SPACE REQUIRED, EXCLUSIVE OF SLUDGE DISPOSAL AREA (m^2)	Approximately 500
4.14	PERSONNEL (MAN-HOURS/YEAR)	
4.14.1	Operating	0 } Boiler plant and gas cleaning plant is operated
4.14.1.1	Specialists	0 } by 2 men - engineer and boiler operator - on shifts.
4.14.1.2	Unskilled	0 } Gas cleaning plant does not require any additional operator.
4.14.2	Maintenance and repair	1000 estimated
4.15	ENVIRONMENTAL LOAD	
4.15.1	Waste water treatment process	Effluents from scrubbers are fed into existing waste water discharge channel containing alkaline wastes and calsium hypochlorite. The oxidation process $SO_2 \rightarrow SO_3$ is very fast under these conditions
4.15.2	Concentrations	Average by weight in liquid discharge to sea. By full load of boilers. 2.5% S in oil and 90% efficiency: max. 190 mg SO_4/l, max. 1.5 mg fly ash/l, 35 µg Ni/l, 120 µg V/l.
4.15.3	Appearance of flue gas discharge - any mist problems?	No

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7
4.16	FGD SYSTEM OPERATION	
4.16.1	% of boiler load FGD can operate	100
4.16.2	Lag time	There is no noticeable time lag
5.	ACTUAL COSTS FOR TOTAL FGD INSTALLATION (year)	
5.1	CAPITAL COSTS ($)*	2.16×10^6
5.1.1	Scrubber	
5.1.2	Absorbent/regeneration system	
5.1.3	Sludge disposal system	
5.1.4	Site improvements	
5.1.5	Land, roads, tracks, substation	
5.1.6	Engineering costs	
5.1.7	Contractor's fee	
5.1.8	Interest during construction	
	Construction periods (months)	Net 7
5.1.9	License fees	
5.1.10	Other	
5.1.11	Total ($)	2.16×10^6
	($/kWe)	43.2 Based on a theoretical electric generating capacity of 130 MW x 0.38 = 50 MWe (net efficiency of power plant = 38%)

* 0.18 $/Nkr.

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7	
5.2	ANNUAL COSTS ($)*		
5.2.1	Interest	215 000	
5.2.2	Depreciation	215 000	
5.2.3	Insurance and taxes		
5.2.4	Total fixed costs	430 000	
5.2.5	Labor and overhead	0	
	Average man hour cost	0	
	cost/year	0	
5.2.6	Raw material breakdown		
	Annual cost		
	Unit cost		
5.2.7	Utilities,		
	Annual costs, unit cost		
	Electricity	55 000 $/year (no reheat)	13.5 $/MWh (unit cost)
	Sea Water **	50 000 $/year	4.5 $/1000 m^3 (unit cost)
	Steam		
	Fuel		
5.2.8	Maintenance cost per year	20 000 estimated	
5.2.9	Other costs, list		
5.2.10	Total variable cost per year	125 000	
5.2.11	Total annual cost	555 000	
5.3	WASTE DISPOSAL COST ($)		
	Unit cost	0	
	Annual cost	0	
5.4	BY-PRODUCT CREDIT ($)	0	

* 0.18 $/Nkr.

** Costs of sea water from existing installation (pumping and distribution)

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		TOTAL FOR BOILER No 5, 6 AND 7
5.5	NET ANNUAL COST mills/kWeh •	
5.5.1	Cost for last year	3.6 } Calculations based on a theoretical generating capacity of 50 MWe, 8760 operating hours per year and an average capacity factor of 0.35. No reheat.
5.5.2	Cost at maximum continous rating	1.3 }
5.5.3	Cost without FGD	
6.	ENERGY REQUIREMENTS	
	Pumps (kW	250 Booster pumps for the FGD installations
	Fan (kW	350
	Reheat (kW)	max 650 Corresponds to 200°C heat loss of max. by-pass of economizer.
	Reductant chemicals (kW)	0
	Other (kW)	0
	Total (kW)	600 Without reheat.
	(kWh/kg SO_2 removed)	1.1 Without reheat and 2.5% wt sulfur in oil.

• Includes fixed charges
1 $ = 1000 mills
0.18 $/Nkr.

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		BOILER No 5	BOILER No 6	BOILER No 7
7.	PERFORMANCE HISTORY; OPERATING PROBLEMS AND SOLUTIONS			
7.1	Scrubber system	No special problems	No special problems	No special problems
7.2	Demister	No special problems	No special problems	No special problems
7.3	Reheater	The valve has had a tendency to stick. (b)	With the valve closed condensation causes some acid to run back against the valve. (a).	No special problems

(a) During commissioning or shake down

(b) During regular operation

A/S NORSK VIFTEFABRIKK

Norsk Hydro a.s., Porsgrunn Fabrikker

		BOILER No 5	BOILER No 6	BOILER No 7
7.4	Fan	Problems with the inlet damper on the fan. (a)	Minor problem with inlet guide vane control. (a)	Minor problem with inlet guide vane control. (a)
7.5	Sludge system			
7.6	Regeneration system			
7.7	By-product system			
7.8	Other	The cooling part has had leakages because of corrosion. (b). The compensators in the gas duct has been a weak point. (b). Regulation problems during commissioning. (a).	No special problems	No special problems. One incident of a broken pipe in discharge system (b).
7.9	Availability	Time (year, month) / Availability (%): Jan. 96.6; Febr. 99.4; 1976 March 97.0; April 100.0; May 85.3; June 100.0	Time (year, month) / Availability (%): March 96.2; April 98.9; 1977 May 99.5; June 98.3; July 98.2; Aug. 99.7	Time (year, month) / Availability (%): March 99.7; April 99.4; 1977 May 99.7; June 99.6; July 99.6; Aug. 95.8

(a) During commissioning or shake down

(b) During regular operation

APPENDIX I. AREA SURROUNDING PLANT SITE

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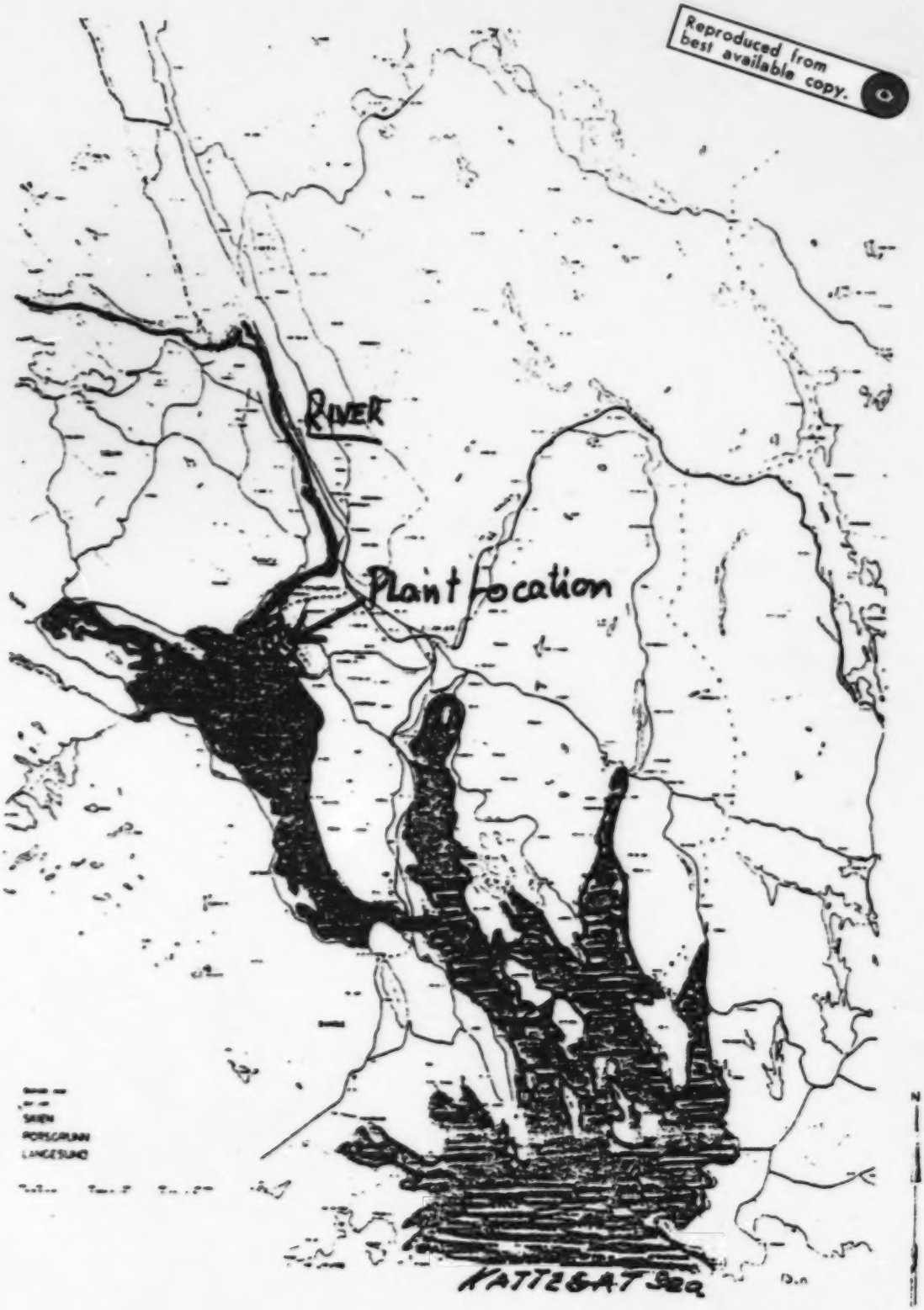

APPENDIX 2. PARTICULATE REMOVAL EQUIPMENT

The FGD-plant installed after boiler No. 5 has multi-cyclones with capacity amounting to one-third of the total gas flow. Boiler desooting is accomplished at this flue gas capacity.

In the case of FGD-plants for boiler No. 6 and 7, casings for multicyclones and ductwork have been installed. Particle size distribution and boiler particulate emission rate will be measured and evaluated before a decision will be taken with regard to cyclone installation.

For the seawater process, the demand for dry dust collection will probably be the same as required with regard to atmospheric pollution, in order to minimize effluent of objectionable materials (toxic trace elements) to the sea.

The most suitable equipment must be evaluated in each individual case based on efficiency requirement and composition of the flue gas.
The dust collector ahead of the Fläkt-Hydro FGD-system may be, for an oil or coal fired station, electrostatic precipitator or bag filter.
In the case of extreme requirements, the dry collector may be combined with a wet prescrubber in closed liquid loop operation.

APPENDIX 3 PROCESS DESCRIPTION

A flow sheet displaying the system as installed in the boiler house at Porsgrunn Fabrikker is shown in figure 2, chapter 2.2.1 in the main report.

BOILERS AND FGD CONTROL MODE

Three automatic boilers generate steam for supply of process steam to various chemical factories on plant area. Steam demand may vary rapidly and over a broad range. Boiler No. 5 can change load from 20 - 100% within one minute, while boiler Nos. 6 and 7 take three minutes for a corresponding load change. Ahead of the boilers are installed forced-draught fans for supply of combustion air. All of them are equipped with inlet guide vane control.

Boiler No. 5 was retrofitted with FGD system in 1975. Flue gas pressure after the boiler should be controlled at - 10 mm WG with maximum deviations of $\pm$ 15 mm WG. This claim was mainly set forth due to potential corrosion damage of the mild steel by-pass stack. However, if an underpressure could be maintained after the boiler, flue gas leakage through the shut-off damper leading to the by-pass stack would be effectively prevented.

The solution to this control problem is regulation of the inlet guide vane damper ahead of the flue gas fan which is controlled by pressure measurement in the duct after the boiler. Additional to this, flue gas recirculates through the flue gas fan for loads between 20 - 60%. The damper in the recirculation loop is controlled by fuel oil consumption. Above 60% load the damper in the recirculation loop is fully closed and pressure is easily controlled merely by inlet guide vane control ahead of the flue gas fan. This was a successful approach to the control problem and has afterwards been applied with renewed success on boiler Nos. 6 and 7. One slight difference in control occurs between No. 5 and Nos. 6 and 7. For Nos. 6 and 7 the dampers for control of the flue gas recirculation are controlled by the amount of

combustion air instead of fuel oil consumption. This modification was worked out purely out of practical reasons.

LIQUID SYSTEM

Seawater Supply

A large seawater pumping station with surplus capacity was available within the plant. Sea water intake depth is 20 m below sea level, ensuring high salinity sea water throughout the year. A supply pipe in GRP from the pump station leading to the top floor of the boiler house, and a pressure increase pump, had to be installed additionally for supply of 1350 m^3/hr of sea water. This quantity is distributed with 270 m^3/hr to No. 5 and 540 m^3/hr to Nos. 6 and 7 respectively. Approximately one tenth of the sea water flow is supplied to the venturi scrubber for flue gas cooling, the remaining sea water quantity being fed to the second scrubber for SO_2 removal. Sea water is supplied at a constant rate independently of boiler load.

Waste liquid system

Liquid from 3 scrubbers are collected in a common tank and flows by gravity through a closed GRP pipe and into the main sewer from the magnesium factory. The sewer from the Mg-factory is also seawater, but enriched in lime, and holds a pH of approximately 10.5. This sewer is saturated with oxygen and flow rate is about 7000 m^3/hr. The acidic scrubber effluent (pH 2,2 - 5) is hence neutralized. Oxidation of sulphite is accomplished by also piping another sewer containing ample amounts of $Ca(OCl)_2$ into the main sewer. Oxidation of sulfite into sulfate proceeds very rapidly under the conditions prevailing and any COD imposed on the immediate vicinity of discharge is eliminated. The liquid treatment system is, of course, a site specific solution.

In the general case neutralization has to be carried out by employing enough sea water to arrive at the desired pH in effluent water, and sulfite oxidation by dissolving air into the effluent by means of appropriate aeration equipment.

Flue gas purification system

The flue gas train consists of a particulate precollector, a low pressure multi venturi quencher, a countercurrent packed tower, and a mixing unit for accomplishing reheat by addition of hot flue gas extracted upstreams of the economizer. The particulate precollector is of multi-cyclone design. The chief objective of the precollector is to prevent particulate material to enter into the subsequent sea water scrubbing stages and get collected there.

The precollectors are controlled so as to maintain a constant pressure drop and thus a maximum particulate removal efficiency independently of boiler load. For the new boilers Nos. 6 and 7 provisions have been made for installation of multi-cyclone panels (see appendix 2.13).

The flue gas then flows through a low pressure multi-venturi quencher where sea water is injected and gas cooling takes place. A fresh-water injection system is part of the venturi. The fresh water is automatically triggered off in case of seawater supply failure, in order to protect the subsequent polyester tower against heat deterioration.

The flue gas then flows through a counter-current packed tower, a demister, and a reheat unit and is discharged into the atmosphere through a stack mounted on top of the tower. Due to the intimate counter-current once through contact between sea water and flue gas, outlet gas temperature is very close to inlet seawater temperature. This results in an increase in flue gas density, surpassing the density of surrounding air with approximately 5%. During summer time the flue gas is heavier than the relatively warm surrounding air. In order to ensure plume rise, hot flue gas may be added. Maximum reheat capacity is a 25^{o} temperature increase.

APPENDIX 4.

Major elements in seawater

Ion	g/kg at Salinity = 35 °/oo
CL^-	19.354
SO_4^{2-}	2.712
Br^-	0.9673
F^-	0.0013
B	0.0045
Na^+	10.77
Mg^{2+}	1.29
Ca^{2+}	0.4121
K^+	0.399
Sr^{2+}	0.0079

Protolytic material in seawater ($^{mol}/_{l}$)

Seawater (pH ca. 8,3 at 10°C and 35 °/oo)

bicarbonate	$20 \cdot 10^{-4}$
carbonate	$2 \cdot 10^{-4}$
total boron	$4.5 \cdot 10^{-4}$
borate	$1 \cdot 10^{-4}$
total phosphate	$1 \cdot 10^{-6}$
total arsenite	$4 \cdot 10^{-8}$
sulphide	$2 \cdot 10^{-5}$
organic acids	traces only

Typical data for seawater from Frierfjord

Salinity	32 °/oo
Alkalinity	2.3 meq/l
Temperature	5 - 15 °C